

## 4.0 Applicable Requirements and Standards

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This section presents a review of the air quality regulations that will govern permitting and operation of the proposed Project. Specifically, the following regulations and standards were reviewed for applicability to the proposed Project:

- NAAQS.
- PSD regulations.
- Good engineering practice (GEP) stack height regulations.
- NSPS.
- National Emissions Standards for Hazardous Air Pollutants (NESHAP).
- Compliance assurance monitoring (CAM).
- EPA's Acid Rain Program (ARP) regulations.
- Risk management program (RMP).
- Title V permit program.
- Cross-State Air Pollution Rule (CSAPR).
- VDEQ, VAC.
- Virginia SIP.

Federal regulatory programs, as administered and delegated by EPA, have been developed under the authority of the CAA and its amendments. The following subsections review the key elements of the federal regulatory program and the impact they have on the permitting and operation of the proposed Project. Attention is placed on NAAQS (40 CFR 50), PSD (40 CFR 52.21), NSPS (40 CFR 60), NESHAP (40 CFR 61 and 63), CAM (40 CFR 64), RMP (40 CFR 68), ARP regulations (40 CFR 72, 73, 75, 76, and 77), and CSAPR (40 CFR 97). Discussion of applicable Virginia regulatory citations is also included in this section.

## 4.1 Classification with Regard to Ambient Air Quality

The 1970 CAA gave EPA specific authority to establish the minimum level of air quality that all states would be required to achieve. These minimum values or standards were developed to protect public health (primary) and welfare (secondary). Table 4-1 presents the federally promulgated standards, adopted by Virginia as state standards. Table 4-1 also includes Virginia ambient air quality standards (AAQS).

The 1990 CAA Amendments called for a review of the ambient air quality of all regions of the United States. By March 15, 1991, states were required to file with EPA designations of all areas as either attainment, nonattainment, or unclassifiable. Areas of the country that had monitored air quality levels equal to or better than these standards (i.e., ambient concentrations less than a standard) as of March 15, 1991, became designated as attainment areas, while those areas where monitoring data indicated air quality concentrations greater than the standards became known as nonattainment areas.

The designation of unclassifiable indicates there is insufficient monitoring data to prove the area has attained the federal standards; however, the limited data available indicates the standard has been achieved. Areas with this classification are treated by EPA as attainment areas for permitting purposes.

Table 4-2 lists the current federal air quality classifications for each criteria pollutant for the Project area in Charles City County. The designation of an area has particular importance for a proposed project as it is a factor that, in part, determines whether a pollutant is subject to PSD review or nonattainment new source review (NNSR).

Major new sources or major modifications to existing major sources located in attainment or unclassifiable areas are required to obtain a PSD permit prior to initiation of construction. Similar sources located in areas designated as nonattainment or that adversely impact such areas are required to undergo permitting under the provisions of the nonattainment NNSR program. In either case, it is necessary, as a first step, to determine the air quality classification of a project site. For the proposed Project, only PSD review is potentially applicable, because the attainment

Table 4-1. Ambient Air Quality Standards

Pollutant	Averaging Period*	NAAQS ( $\mu\text{g}/\text{m}^3$ †)		VDEQ Regulation Standards ( $\mu\text{g}/\text{m}^3$ †)	
		Primary	Secondary	Primary	Secondary
SO <sub>2</sub>	Annual‡	80	—§	80	—§
	24-hour‡	365	—§	365	—§
	1-hour	196	—§	196	—§
	3-hour	—§	1,300	—§	1,300
PM <sub>10</sub>	24-hour	150	150	150	150
PM <sub>2.5</sub>	Annual	12	15	12	15
	24-hour	35	35	35	35
CO	8-hour	10,000	—§	10,000	—§
	1-hour	40,000	—§	40,000	—§
Ozone	8-hour	0.070 ppm	0.070 ppm	0.070 ppm	0.070 ppm
NO <sub>2</sub>	Annual	53 ppb	53 ppb	53 ppb	53 ppb
	1-hour	100 ppb	—§	100 ppb	—§
Lead	3-month£	0.15	—§	0.15	—§

Note: ppm = part per million. ppb = part per billion. NO<sub>2</sub> = nitrogen dioxide.

\*National short-term ambient standards may be exceeded once per year; annual standards may never be exceeded. Virginia short-term standards may be exceeded once per year, annual standards may never be exceeded. Ozone standard is attained when the expected number of days of an exceedance is equal to or less than one.

†Standards expressed in micrograms per cubic meter ( $\mu\text{g}/\text{m}^3$ ) unless otherwise noted.

‡Final rule signed June 2, 2010. The 1971 annual and 24-hour SO<sub>2</sub> standards were revoked in this rulemaking. However, these standards remain in effect until one year after an area is designated for the 2010 standard, except in areas designated nonattainment for the 1971 standards, where the 1971 standards remain in effect until implementation plans to attain or maintain the 2010 standard are approved.

§No ambient standard for this pollutant and/or averaging period.

£The rule signed October 15, 2008, finalized a new lead standard. The 1978 lead standard of 1.5  $\mu\text{g}/\text{m}^3$  as a quarterly average remains in effect until one year after an area is designated for the 2008 standard, except in areas designated nonattainment for the 1978 standard, where, the 1978 standard remains in effect until implementation plans to attain or maintain the 2008 standard are approved.

Sources: 40 CFR 50.  
9 VAC 5-30.

**Table 4-2. Classification of Charles City County, Virginia, for Each Criteria Pollutant**

Pollutant	Attainment Status
CO	Unclassifiable/attainment
SO <sub>2</sub>	Attainment*
NO <sub>2</sub>	Unclassifiable/attainment
PM <sub>10</sub>	Unclassifiable/attainment
PM <sub>2.5</sub>	Unclassifiable/attainment
Ozone (8-hour)	Unclassifiable/attainment
Lead	Unclassifiable/attainment

Note: CO = carbon monoxide.

NO<sub>2</sub> = nitrogen dioxide.

PM<sub>2.5</sub> = particulate matter less than or equal to 2.5 micrometers.

PM<sub>10</sub> = particulate matter less than or equal to 10 micrometers.

SO<sub>2</sub> = sulfur dioxide.

\*One-hour SO<sub>2</sub> NAAQS classification has not been finalized.

Source: 40 CFR 81.347.

status for Charles City County, which is located in the State Capital Intrastate Air Quality Control Region, is either unclassifiable/attainment or attainment for all pollutants.

## 4.2 PSD Program

### 4.2.1 PSD Applicability

The determination of whether PSD regulations are applicable to a specific project must be conducted in two parts: first dealing with the air quality status of the location of the Project, and second evaluating the type and quantity of PSD-regulated pollutants that will be emitted. For the regulations to apply to a given project, it must first be determined whether the proposed location is in an area that has been classified as attainment or as unclassifiable. Because the facility is located in Charles City County, which is designated as attainment or unclassifiable for the criteria pollutants, PSD review will apply as discussed in the following paragraphs.

The Project's PTE is reviewed to determine whether it constitutes a major stationary source or a major modification. A major stationary source is defined as either one of the sources identified in 9 VAC 5-80-1615.C (see Table 4-3) that has a PTE of 100 tpy or more of any regulated pollutant, or any other stationary source that has the PTE of 250 tpy or more of a regulated pollutant. A major modification is defined as a source having an increase in emissions above the PSD significant emissions rates (SERs), as identified in Table 4-4. Combined-cycle CT generators with HRSG are considered a fossil fuel-fired steam electric plant under PSD rules. PTE has a special meaning here, as it is determined on an annual basis after the application of air pollution control equipment based on the maximum hourly emissions times 8,760 hours, or any other practically enforceable restriction that would restrict the hours or the operation or emissions of the emissions source. Once it is determined any pollutant exceeds the major source threshold, each of the remaining pollutants is subject to PSD review if the PTE exceeds the SERs listed in Table 4-4.

The Project is subject to PSD for NO<sub>x</sub>, PM, PM<sub>10</sub>, PM<sub>2.5</sub>, VOC, CO, H<sub>2</sub>SO<sub>4</sub>, and GHG, as previously shown in Table 3-8.

**Table 4-3. Major Stationary Source Categories with a 100-tpy Threshold**

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Fossil fuel-fired steam electric plants of more than 250 MMBtu/hr heat input
Coal cleaning plants (with thermal dryers)
Kraft pulp mills
Portland cement plants
Primary zinc smelters
Iron and steel mill plants
Primary aluminum ore reduction plants
Primary copper smelters
Municipal incinerators capable of charging more than 250 tons of refuse per day
Hydrofluoric, sulfuric, or nitric acid plants
Petroleum refineries
Lime plants
Phosphate rock processing plants
Coke oven batteries
Sulfur recovery plants
Carbon black plants
Primary lead smelters
Fuel conversion plants
Sintering plants
Secondary metal production plants
Chemical processing plants
Fossil-fuel boilers (or combination thereof) totaling of more than 250 MMBtu/hr heat input
Petroleum storage and transfer units with a total storage capacity exceeding 300,000 barrels
Taconite ore processing plants
Glass fiber processing plants
Charcoal production plants

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Source: 9 VAC 5-80-1615.C.

Table 4-4. PSD SERs

Pollutant	SER (tpy)
CO	100
NO <sub>x</sub>	40
SO <sub>2</sub>	40
PM	25
PM <sub>10</sub>	15
PM <sub>2.5</sub>	10
Ozone	40 of VOCs
Lead	0.6
Fluorides	3
H <sub>2</sub> SO <sub>4</sub> mist	7
Total reduced sulfur	10
Reduced sulfur compounds	10
Hydrogen sulfide	10
GHGs CO <sub>2</sub> e	75,000

Source: 9 VAC 5-80-1615.C and 9 VAC 5-85-50.

## 4.2.2 PSD Program Requirements

The following provides a summary of the application requirements for projects subject to PSD.

### 4.2.2.1 Best Available Control Technology

The requirements for BACT were promulgated within the framework of PSD in the 1977 CAA Amendments. Guidelines for the evaluation of BACT can be found in EPA's Air Pollution Control Cost Manual (EPA, 2002) and in the PSD/New Source Review Workshop Manual (EPA, 1990 DRAFT). These guidelines were drafted by EPA as a framework or tool for the BACT process. More recently, EPA has published guidance on BACT for GHG emissions (<http://www.epa.gov/nsr/ghgpermitting.html>). BACT for most states, including Virginia, is determined by the state permitting authority using permitting procedures that have been adopted consistent with the authority granted through EPA's SIP approval of the Virginia PSD program.

The regulatory definition of BACT for affected sources locating in Virginia is:

“[A]n emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the board, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant that would exceed the emissions allowed by any applicable standard under 40 CFR Parts 60, 61, and 63. If the board determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means that achieve equivalent results.” (9 VAC 5-80-1615.C.)

Although BACT is typically an emissions limit, BACT can also be a work practice standard in certain circumstances, typically if an emissions limit is not feasible. One example of a work practice standard that can impact a BACT determination is a limitation on the hours of operation for a source. Another example is the specification of a particular control device in lieu of an



emissions limit. BACT limits are determined by the permitting authority (in this instance, VDEQ) based on a case-by-case analysis that takes into account site-specific characteristics, including “energy, environmental, and economic costs and other costs” (9 VAC 5-80-1615.C). BACT does not require a redefinition of the proposed source or use of unproven technology. BACT is not necessarily the lowest emissions level ever seen, but the lowest level achievable by the applicant for the particular proposed source at issue under worst-case foreseeable conditions.

A BACT limit must be achievable. Generally, achievable in the context of BACT means an emissions limit that the source can meet on a continual basis over each averaging period for the lifetime of the facility. BACT limits should be set at levels the source can meet under all reasonable foreseeable worst-case conditions. A permitting authority determines what is achievable for a source, exercising its technical judgment on a case-by-case basis.

In addition to being achievable, a control technology must be available to be considered in a BACT determination. To be available, a control technology must be demonstrated in practice. This means the technology has progressed beyond the conceptual stage and beyond research and development or the pilot testing phase. The technology must have been demonstrated successfully on full-scale operations for a sufficient time to be considered proven. BACT does not require an applicant to employ technologies not proven to work; theoretical, experimental, or developing technologies are not available under BACT. Technologies with questionable or dubious reliability are likewise not considered available under BACT, and the applicant is not required to use them. Moreover, vendor sales literature about what a technology might be able to achieve in some limited situation is not relevant to a BACT determination.

Finally, BACT is determined on a pollutant-by-pollutant basis. When establishing BACT for individual pollutants, however, a permitting authority must also consider possible interactions among the pollutants as well as other collateral environmental impacts of particular technologies, such as water usage or the creation of a waste stream. Section 5.0 presents BACT analyses for the Project.

#### **4.2.2.2      Air Quality Monitoring Requirements**

In accordance with requirements of 9 VAC 5-80-1735, a PSD application must contain an analysis of existing ambient air quality data in the area to be affected by the proposed Project if the Project would result in a net significant emissions increase. The analysis of existing air quality can be air monitoring data from either a state-operated or private network, or by a preconstruction monitoring program specifically designed to collect data in the vicinity of the proposed source. The requirement for onsite air quality monitoring is based on the impact levels provided in 9 VAC 5-80-1695.E.

Ambient air monitoring for a period of up to one year may be required to properly satisfy this monitoring requirement. This condition may be waived if a project would cause an impact less than EPA-specified de minimis monitoring levels established by the Virginia State Air Pollution Control Board (see Table 4-5).

#### **4.2.2.3      Source Impact Analysis**

A source impact analysis must be performed for a proposed project subject to PSD review for each pollutant for which the increase in emissions exceeds the SER to demonstrate the Project will not cause or contribute to a violation of NAAQS or PSD increment. The PSD regulations specifically provide for the use of atmospheric dispersion modeling in performing impact analyses, estimating baseline and future air quality levels, and determining compliance with NAAQS and allowable PSD increments. In accordance with 9 VAC 5-80-1725, designated EPA models, identified in 40 CFR 51, Appendix W, must normally be used in performing air quality analyses. Use of other than EPA-approved models requires written approval and opportunity for public notice and comment prior to use. Guidance for the use and application of dispersion models is presented in the EPA publication Guideline on Air Quality Models (EPA, 2005). The source impact analysis for criteria pollutants may be limited to only the new or modified sources if a net increase in impact due to the new or modified source is below the significant impact levels (SILs) presented in Table 4-6.

Various periods of meteorological data can be used for an impact analysis. However, a minimum one-year period of onsite data, or a five-year period of representative meteorological data, is normally required.

Table 4-5. PSD De Minimis Monitoring Threshold Concentrations

Pollutant	Averaging Period	Threshold Concentration ( $\mu\text{g}/\text{m}^3$ )
CO	8-hour	575
NO <sub>2</sub>	Annual	14
SO <sub>2</sub>	24-hour	13
PM/PM <sub>10</sub>	24-hour	10
Ozone	Not applicable	*
Lead	3-month	0.1
Fluorides	24-hour	0.25
Total reduced sulfur	1-hour	10
Reduced sulfur compounds	1-hour	10
Hydrogen sulfide	1-hour	0.2

Note: CO = carbon monoxide.

NO<sub>2</sub> = nitrogen dioxide.

PM<sub>2.5</sub> = particulate matter less than or equal to 2.5 micrometers.

PM<sub>10</sub> = particulate matter less than or equal to 10 micrometers.

SO<sub>2</sub> = sulfur dioxide.

\*No de minimis air quality level is provided for ozone.

Source: 9 VAC 5-80-1695.E

Table 4-6. Allowable PSD Increments and Significant Impact Levels

Pollutant	Averaging Time	PSD Increments		SILs		NAAQS
		Class I	Class II	Class I*	Class II	
PM <sub>10</sub>	Annual arithmetic mean†	4	17	0.2	1	NA
	24-Hour maximum‡	8	30	0.3	5	150
PM <sub>2.5</sub> §	Annual arithmetic mean†	1	4	0.06	0.3	12
	24-Hour maximum‡	2	9	0.07	1.2	35
SO <sub>2</sub>	Annual arithmetic mean†	2	20	0.1	1	80
	24-Hour maximum‡	5	91	0.2	5	365
	3-Hour maximum‡	25	512	1	25	1,300
	1-Hour maximum£	NA	NA	NA	7.86	196
CO	8-Hour maximum	NA	NA	NA	500	10,000
	1-Hour maximum	NA	NA	NA	2,000	40,000
NO <sub>2</sub>	Annual arithmetic mean†	2.5	25	0.1	1	100
	1-Hour maximum£	NA	NA	NA	7.5	188

Note: CO = carbon monoxide.

NA = not applicable, i.e., no increment exists.

NO<sub>2</sub> = nitrogen dioxide.

PM<sub>2.5</sub> = particulate matter less than or equal to 2.5 micrometers.

PM<sub>10</sub> = particulate matter less than or equal to 10 micrometers.

SO<sub>2</sub> = sulfur dioxide.

\*Class I SILs were proposed in Federal Register July 23, 1996.

†PSD increment not to be exceeded.

‡PSD increment not to be exceeded more than once per year.

£While there are no EPA promulgated SILs for the 1-hour SO<sub>2</sub> and NO<sub>2</sub> NAAQS, interim values have been provided.

§SILs for PM<sub>2.5</sub> exist for the purpose of determining if a source has a significant contribution to a modeled violation. The SILs do not exist for the purposes of avoiding a cumulative impact analysis.

Source: ECT, 2016.

#### 4.2.2.4 PSD Increments

PSD regulations specify that new major sources or modifications to existing major sources may change baseline air quality only by a defined amount. This limited incremental degradation is known as a PSD increment. PSD increments have been established for Class I and Class II areas for PM<sub>10</sub>, PM<sub>2.5</sub>, SO<sub>2</sub>, and nitrogen dioxide (NO<sub>2</sub>) (see Table 4-6).

The allowable change, or increment, is dependent on the classification of the area in which the action is to take place. When PSD regulations were first promulgated, three area classifications were proposed based on criteria set in the 1977 CAA.

Class I areas are federally protected and include specifically defined national parks, national forests, and wilderness areas. Class III increments are the least restrictive of the three PSD Classes; however, to date, no Class III areas have been officially designated. The remainder (and vast majority) of the country (including Charles City County) is designated as a Class II area.

#### 4.2.2.5 Additional Analyses

In addition to the standard air quality analyses, federal regulations require an analysis of the impairment to visibility and the effects on soils and vegetation that would occur as a result of project construction and operation. Impacts due to commercial, residential, industrial, and other growth in the vicinity of the Project also must be addressed to the extent they are a result of the proposed action. This additional analysis is provided in Section 8.0 of this application.

### 4.3 Good Engineering Stack Height Analysis

The 1977 CAA require the degree of emissions limitation required for control of any pollutant not be affected by a stack which exceeds the GEP height (EPA, 1985). Further, no dispersion credit is given during air quality modeling for stacks that exceed GEP. GEP stack height is defined as the highest of one of these three:

- 65 meters.
- A height established by applying the formula:  $H_{GEP} = H + 1.5 L$ :

where: HGEP = GEP stack height.

H = height of the structure or nearby structure.

L = lesser dimension (height or projected width) of the nearby structure.

- A height demonstrated by fluid modeling or field study.

A structure or terrain feature is considered nearby if a stack is within a distance of five times the structure's height or maximum projected width. Only the smaller value of the height or projected width is used, and the distance to the structure cannot be greater than 0.8 kilometer (EPA, 1985). Although GEP stack height regulations require the stack height used in modeling for determining compliance with NAAQS and PSD increments not exceed GEP stack height, the actual stack height may be greater.

The stack height regulations also increase GEP stack height beyond that resulting from the formula in cases where plume impaction occurs. Plume impaction is defined as concentrations measured or modeled to occur when the plume interacts with elevated terrain. Elevated terrain is defined as terrain that exceeds the height calculated by the GEP stack height formula. Based on two criteria cited in a July 8, 1985, Federal Register preamble to the stack height rules discussing the role of terrain in influencing the emitted plume at the source location, there is no significant terrain that would induce downwash within 0.5 kilometer and at least a 10-percent terrain height relative to the distance from the source. Therefore, plume impaction was not considered in determining the GEP stack height for the proposed Project.

Stacks to be constructed at the Project site will each be less than or equal to 65 meters and modeled at their actual stack elevation. Therefore, the modeling complies with GEP regulations.

#### 4.4 Applicability of NSPS

The NSPS potentially applicable to this Project include:

- Subpart A, General Provisions.
- Subpart Db, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.

- Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units.
- Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels.
- Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
- Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
- Subpart KKKK, Standards of Performance for Stationary CTs.
- Subpart TTTT, Standards of Performance for GHG Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units.

Each of these potentially applicable subparts is discussed further in the following subsections.

#### **4.4.1 Subpart A, General Provisions**

Certain provisions of 40 CFR 60, Subpart A, apply to the owner or operator of any stationary source subject to NSPS. Because the proposed facility will be subject to NSPS, the proposed project will be required to comply with applicable provisions of Subpart A. Table 4-7 identifies Subpart A provisions that impose requirements on the proposed Project.

#### **4.4.2 Subpart Db, Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units**

NSPS Subpart Db applies to steam generating units in which construction commenced after June 19, 1984, and that have a maximum design heat input capacity greater than 100 MMBtu/hr. The proposed natural gas-fired auxiliary boiler with a rated capacity of 105 MMBtu/hr will be subject to this subpart. The boiler will be exempt from the SO<sub>2</sub> and PM emissions limits, because it will burn only natural gas. The proposed BACT emissions limits for the auxiliary boiler will assure compliance with the 0.10 or 0.20 pound per million British thermal units (lb/MMBtu) NO<sub>x</sub> (low and high heat release rate units) emissions limits in Subpart Db. Because the annual capacity factor for the auxiliary boiler will not exceed 10 percent, Subpart Db does not require a CEMS. Compliance with the Subpart Db NO<sub>x</sub> emissions limit will be based on stack testing. C4GT will also comply with applicable Subpart Db monitoring, recordkeeping, and reporting requirements.

**Table 4-7. Summary of Regulatory Requirements of NSPS Subpart A, General Provisions**

40 CFR 60 Subpart A Section	Requirement	Compliance Action
60.7	Initial notification and recordkeeping	C4GT will submit NSPS-related notifications to EPA Region III and VDEQ for the proposed project in a timely manner.
60.8	Performance tests	C4GT will conduct required performance tests using designated reference test methods.
60.11	Compliance with standards and maintenance requirements	C4GT will operate and maintain the units using good air pollution control practices.
60.13	Monitoring requirements	C4GT will use pollutant monitoring methods outlined in 40 CFR 60.13.
60.19	General notification and reporting requirements	C4GT will follow NSPS report and notification formats and schedules set forth in 40 CFR 60.19.

Source: ECT, 2016.



The proposed duct burners are not subject to this rule; they are subject to Subpart KKKK requirements instead, as described in Section 4.4.7.

#### **4.4.3 Subpart Dc, Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units**

NSPS Subpart Dc applies to steam generating units that commenced construction after June 9, 1989, and have a maximum design heat input capacity between 10 and 100 MMBtu/hr. The dew point heater, rated at 16 MMBtu/hr, is subject to this subpart, because the heater is greater than 10 MMBtu/hr and less than 100 MMBtu/hr. Although the 16-MMBtu/hr heater is subject to Subpart Dc, PM and SO<sub>2</sub> emissions standards under Subpart Dc are not applicable, because the heater will only burn natural gas. Subpart Dc does not include NO<sub>x</sub> emissions standards. C4GT will comply with applicable Subpart Dc monitoring, recordkeeping, and reporting requirements.

#### **4.4.4 Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels**

As part of the proposed Project, the facility will have one 3,000-gallon storage tank that will hold ULSD fuel used in the emergency diesel engine and one 400-gallon storage tank that will hold ULSD fuel used in the firewater pump. NSPS Subpart Kb regulates storage vessels with a capacity greater than 75 cubic meters (19,813 gallons) that are used to store volatile organic liquids for which construction, reconstruction, or modification is commenced after July 23, 1984. Also, Subpart Kb does not apply to storage vessels storing a liquid with a maximum true vapor pressure less than 0.5 pound per square inch absolute (psia). Subpart Kb does not apply to the proposed storage tanks, because the capacity is less than 75 cubic meters, and because the maximum true vapor pressure of the stored liquid (ULSD fuel) will be less than 0.01 psia, well below the 0.5-psia Subpart Kb applicability criteria.

#### **4.4.5 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines**

The diesel-fired emergency generator and diesel-fired firewater pump are subject to 40 CFR 60, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion

Engines. C4GT will comply with all applicable Subpart IIII emissions limitation, monitoring, recordkeeping, and reporting requirements.

#### **4.4.6 Subpart KKKK, Standards of Performance for Stationary CTs**

EPA's Administrator has promulgated a final rule under 40 CFR 60, Subpart KKKK, Standards of Performance for Stationary CTs (see Volume 71, No. 129, Federal Register [FR], July 6, 2006). The regulation applies to NO<sub>x</sub> and SO<sub>2</sub> emissions from each stationary CT generator with a heat input at peak load equal to or greater than 10 MMBtu/hr HHV, which commenced construction, modification, or reconstruction after February 18, 2005.

Only the heat input rate to the CT should be included when determining whether or not this NSPS is applicable to the proposed CTs. Any additional heat input to the associated HRSGs or duct burners should not be included when determining the peak heat input. However, if applicable to the CT, NSPS do apply to emissions from any associated HRSGs and duct burners.

Construction of the proposed CTs will commence after February 2005. The peak load heat input rate of each of the CTs (without the heat input of duct burners) is 3,482 MMBtu/hr firing natural gas. Therefore, the proposed CTs are subject to NO<sub>x</sub> and SO<sub>2</sub> emissions limits in this regulation.

##### **4.4.6.1 Emissions Limits for NO<sub>x</sub>**

The proposed CTs are subject to an emissions standard of 15 parts per million (ppm) at 15-percent oxygen gas or 0.43 pound per megawatt-hour (lb/MWh) when fired with natural gas. If the CTs operate in partial load (less than 75 percent of peak load) or at temperatures less than 0 degrees Fahrenheit (°F), a NO<sub>x</sub> limit of 96 ppm at 15-percent oxygen gas or 4.7 lb/MWh will apply. Compliance is based on the arithmetic average of all hourly applicable NO<sub>x</sub> emissions limits and emissions rates for the most recent 30 unit operating days. If the HRSGs were to operate independently of the CT generators, the CTs would be subject to an emissions standard of 54 ppm at 15-percent oxygen gas or 0.86 lb/MWh.

As discussed in the BACT analysis in Section 5.0, the proposed CTs will reduce NO<sub>x</sub> emissions to 2 ppmvd at 15-percent oxygen gas using low-NO<sub>x</sub> combustors and SCR. Therefore, compliance with these NO<sub>x</sub> emissions limits is expected. Compliance with these emissions

standards will be verified based on CEMS data. The HRSGs will not be operating independently of the CTs; therefore, the 54-ppm NO<sub>x</sub> emissions standard is not applicable for these CTs.

#### **4.4.6.2      Emissions Limits for SO<sub>2</sub>**

The proposed CTs will be subject to an emissions limit of 0.9 lb/MWh gross output or the CTs must not burn any fuel that contains the total potential sulfur emissions in excess of 0.06 lb/MMBtu SO<sub>2</sub> heat input.

C4GT will comply with the input-based emissions standard for SO<sub>2</sub>. The proposed CTs will burn pipeline-quality natural gas with a sulfur content of 0.4 gr/100 dscf; therefore, the SO<sub>2</sub> emissions rate will not exceed 0.00114 lb/MMBtu. Compliance with the SO<sub>2</sub> emissions limit is expected.

#### **4.4.7      Subpart TTTT, Standards of Performance for GHG Emissions from New, Modified, and Reconstructed Stationary Sources: Electric Utility Generating Units**

NSPS Subpart TTTT was promulgated in October 2015 and will be applicable to fossil fuel-fired power plants that commence construction on or after January 8, 2014; therefore, Subpart TTTT will be applicable to the Project. The standard for base load combustion turbines is 1,000 lb/MWh of carbon dioxide (CO<sub>2</sub>) on a gross-output basis. C4GT's CTs and HRSG will have CO<sub>2</sub> emissions below this standard and will comply with applicable monitoring, reporting, and performance test requirements of the rule.

### **4.5      40 CFR 61, NESHAP**

The proposed Project is not subject to any of the 40 CFR 61 NESHAP.

### **4.6      40 CFR 63, NESHAP**

A major source of HAPs is any stationary source that has the potential to emit 10 tpy or more of a single HAP or 25 tpy of combined HAPs. 40 CFR 63, Maximum Achievable Control Technology (MACT), standards have been promulgated for major sources and, in a few cases, for area sources. As shown in Section 3.0 and Appendix B, potential HAP emissions will be

below the major source thresholds for single and combined HAPs. Therefore, the Project will not be a major source of HAP emissions.

#### **4.6.1 Subpart Q, NESHAP for Industrial Process Cooling Towers**

NESHAP Subpart Q does not apply to the proposed cooling tower. Per 40 CFR 63.400(a), “The provisions of this subpart apply to all new and existing industrial process cooling towers that are operated with chromium-based water treatment chemicals and are either major sources or are integral parts of facilities that are major sources as defined in 40 CFR 63.401.” The proposed cooling tower will not use chromium-based water treatment chemicals and will be located at an area source of HAPs (less than 10 tons of a single HAP and less than 25 tons of total HAPs); therefore, this subpart will not apply.

#### **4.6.2 Subpart YYYYY, NESHAP for Stationary CTs**

The CT MACT standard (Subpart YYYYY) only applies to major HAP sources. Therefore, Subpart YYYYY will not apply to the Project.

#### **4.6.3 Subpart ZZZZ, NESHAP for Stationary Reciprocating Internal Combustion Engines**

The emergency generator and firewater pump engine are subject to Subpart ZZZZ, because this standard is applicable to area sources of HAPs as well. Since the engines are new and located at an area source, the requirements of 40 CFR 60, Subpart IIII (for the diesel-fired emergency generator), must be met to meet the requirements of Subpart ZZZZ. The engines will meet applicable NSPS requirements as described in Section 4.4.5.

#### **4.6.4 Subpart DDDDD, NESHAP for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters**

NESHAP Subpart DDDDD applies to boilers and process heaters located at major HAP emissions sources. As C4GT is not a major source of HAPs, this subpart does not apply.

#### 4.6.5 Subpart JJJJJJ, NESHAP for Industrial, Commercial, and Institutional Boilers Area Sources

The area source industrial boiler MACT standard (40 CFR 63, Subpart JJJJJJ) does not apply to gas-fired boilers or process heaters. The proposed auxiliary boiler and dew point heater will be exempt, because they will meet the gas-fired boiler definitions:

- “Boiler means an enclosed device using controlled flame combustion in which water is heated to recover thermal energy in the form of steam and/or hot water. Controlled flame combustion refers to a steady-state, or near steady-state, process wherein fuel and/or oxidizer feed rates are controlled. A device combusting solid waste, as defined in §241.3 of this chapter, is not a boiler unless the device is exempt from the definition of a solid waste incineration unit as provided in section 129(g)(1) of the Clean Air Act. Waste heat boilers, process heaters, and autoclaves are excluded from the definition of Boiler.”
- “Gas-fired boiler includes any boiler that burns gaseous fuels not combined with any solid fuels and burns liquid fuel only during periods of gas curtailment, gas supply interruption, startups, or periodic testing on liquid fuel. Periodic testing of liquid fuel shall not exceed a combined total of 48 hours during any calendar year.”

#### 4.6.6 Subpart UUUUU, Mercury and Air Toxics Standards Rule

NESHAP Subpart UUUUU does not apply to this facility. On December 21, 2011, EPA announced standards to limit mercury, acid gases, and other toxic pollution from power plants. The final rule became effective on April 16, 2012. The Mercury and Air Toxics Standards (MATS) rule reduces emissions of heavy metals, including mercury, arsenic, chromium, and nickel, and acid gases, including hydrochloric acid and hydrofluoric acid. The proposed power plant will burn natural gas only. Therefore, the proposed power plant is not subject to the MATS rule pursuant to 40 CFR 63.9983(b).

### 4.7 Title IV, Acid Rain Provisions

The proposed CTs are fossil fuel-fired combustion devices used to generate electricity for sale, and their capacity serves a generator that exceeds 25 MW. Therefore, the proposed CTs meet the

definition of an affected Phase II unit under EPA's ARP pursuant to Title IV of the 1990 CAA Amendments.

This applicability requires C4GT to:

- Apply for a Phase II acid rain permit to include the new utility units.
- Install CEMS to demonstrate compliance with ARP provisions, meeting the requirements specified in 40 CFR 75.
- Hold allowances equivalent to annual NO<sub>x</sub> and SO<sub>2</sub> emissions.

An acid rain permit application must include the date the units will commence commercial operation and the deadline for monitoring certification (90 unit operating days or 180 calendar days). C4GT will file the appropriate paperwork to apply for an acid rain permit.

C4GT will operate in compliance with applicable provisions of Title IV acid rain rules as adopted by reference under 9 VAC 5-80-360. The facility also will meet applicable acid rain requirements that become effective after the issuance of an acid rain permit.

The facility will develop a Title IV acid rain monitoring plan as required under 40 CFR 72. The plan will include the installation, proper operation, and maintenance of continuous monitoring systems or approved monitoring provisions under 40 CFR 75 for NO<sub>x</sub>, SO<sub>2</sub>, CO<sub>2</sub> or oxygen gas (as a diluent), and opacity. Depending on the monitoring technology available at the time of installation, the plan will cite the specific operating practices and maintenance programs that will be applied to the instruments. The plan also will cite the specific form of records that will be maintained, their availability for inspection, and the length of time they will be archived. The plan will further cite that the acid rain permit and applicable regulations will be reviewed at specific intervals for continued compliance and will cite the specific mechanism to be used to keep current on rule applicability.

## **4.8 RMP, Section 112(r)**

Title III of the 1990 CAA Amendments contains requirements for subject facilities that store and/or process certain hazardous substances for ensuring their safe use. Under these

requirements, facilities must identify and assess their hazards and carry out certain activities designed to reduce the likelihood and severity of accidental chemical releases. Section 112(r) of the CAA, codified in 40 CFR 68, mandates EPA publish rules to develop and implement RMPs for sources with more than the threshold quantity of a listed regulated substance to identify, prevent, and minimize the consequences of accidental releases. The three elements that should be incorporated into an RMP include a hazard assessment, prevention program, and emergency response program.

The facility will store 19-percent aqueous ammonia; as such, RMP requirements do not apply.

#### **4.9      Applicability of Title V, Major Source Operating Permit**

The state of Virginia has been delegated authority to implement the major source operating permit program (Title V) in accordance with the requirements of 40 CFR 70 and Title V of the 1990 CAA Amendments. The operating permit regulations are contained in 9 VAC 5-80, Part II, Article 1, and are briefly summarized in the following text. The minimum requirements for operating permit application contents are provided in 9 VAC 5-80-80.

The proposed CTs have criteria pollutant emissions levels above 100 tpy. 9 VAC 5-80-80 requires major facilities to obtain a permit under this section. Therefore, C4GT will submit a Title V operating permit application to the state of Virginia in a timely manner so it can be deemed complete within 12 months of first fire of the new CT units.

#### **4.10      Clean Air Interstate Rule**

On July 6, 2011, EPA promulgated the CSAPR to replace the Clean Air Interstate Rule (CAIR). CSAPR requires states to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states.

On August 21, 2012, the CSAPR was overturned, and the CAIR requirements remained in effect. On April 29, 2014, however, the U.S. Supreme Court reversed the DC Circuit opinion vacating the CSAPR. On June 26, 2014, the U.S. Supreme Court filed a motion with the U.S. Court of Appeals for the DC Circuit to lift the stay of CSAPR. On October 23, 2014, the U.S. Court of

Appeals (DC Circuit) ordered EPA's motion to lift the stay of the CSAPR be granted. The DC Circuit also provided a schedule for resolving the remaining legal challenges in the case. Except for the changes in dates (moved forward by three years [2012 to 2015]), the CSAPR is being implemented as is. Consistent with the court-ordered schedule, Phase I of CSAPR began in 2015, and any units subject to the rule must comply with applicable requirements. The CAIR requirements, including CAIRNOX, CAIROS, and CAIRSO<sub>2</sub> programs, have ceased to apply post-calendar year 2014.

Aside from the new unit set-asides for ozone season NO<sub>x</sub>, annual NO<sub>x</sub>, and SO<sub>2</sub>, the requirements are similar to those of the CAIR. The facility will comply with the permitting, monitoring, recordkeeping, and reporting requirements set forth by the CSAPR, including the installation and certification of a CEMS.

## **4.11 State Regulatory Review**

In general, VDEQ retains jurisdiction within Charles City County with full delegation from EPA to enforce the air quality programs under the CAA. The emissions sources presented in this document will comply with applicable VDEQ regulations promulgated under Title 9 of Agency 5, State Air Pollution Control Board. This section lists the citations of the applicable state regulations with regulatory requirements.

### **9 VAC 5-20, General Provisions**

The facility will comply with the general provisions as outlined in 9 VAC 5-20.

### **9 VAC 5-50-20, Compliance**

Sixty days after achieving the maximum production rate, but not later than 180 days after initial startup, the facility must not operate any new source in violation of any standard of performance under this regulation. The facility will comply with this regulation.

### **9 VAC 5-50-30, Performance Testing**

This regulation describes performance testing procedures for new or modified sources. The facility will conduct all performance testing in accordance with these regulations.



**9 VAC 5-50-40, Monitoring**

This regulation applies to a CEMS. The facility will comply with these regulations for any CEMS located onsite.

**9 VAC 5-50-50, Notification, Records, and Reporting**

This regulation outlines the notification, recordkeeping, and reporting requirements for new sources. The facility will comply with these regulations.

**9 VAC 5-50-260, Standard for Stationary Sources, and 9 VAC 5-80-1705, Control Technology Review**

These regulations state that “a stationary source shall apply best available control technology for each regulated pollutant that it would have the potential to emit in amounts equal to or greater than the levels in 9 VAC 5-80-1105 C.” A BACT analysis has been conducted for the Project and is presented in Section 5.0.

**9 VAC 5, Chapter 60, Standards for Air Toxics**

This regulation describes the requirements for a stationary source that emits or may emit any toxic pollutant and that either is subject to the new source review program, or emits or may emit at a level greater than the applicable exemption emissions rate. For the proposed facility, air toxics that exceed Virginia air toxics exemption levels are listed in Table 4-8. For those air toxic pollutants above the exemption levels, Sections 6.0 and 7.0 provide a dispersion modeling analysis demonstrating compliance with the Virginia significant ambient air concentrations (SAAC) listed in 9 VAC 5-60-330. Appendix B, Table B-15, provides detailed information on all air toxics along with SAAC levels for any nonexempt air toxics.

**9 VAC 5-80-420, Standard Requirements**

This regulation describes the information needed and limitations for facilities subject to EPA’s ARP. The proposed facility will comply with this regulation.

Table 4-8. Virginia Air Toxic Standards

Pollutant	Facility Emissions Rate		VA Exemption Level		Exempt?	
	lb/hr	tpy	lb/hr	tpy	Hourly	Annual
Acrolein	4.49E-02	1.95E-01	0.02277	0.03335	No	No
Formaldehyde	1.61E+00	7.06E+00	0.0825	0.174	No	No

Note: See Appendix B, Table B-15.

Source: ECT, 20176.

**9 VAC 5-80-1105, Virginia Minor NSR Program**

Virginia has established permitting requirements for projects that do not result in significant increases in emissions but do result in an increase above the applicable permit exemption thresholds shown in Table 4-9. An analysis of the uncontrolled emissions resulting from the Project must be conducted to determine whether Virginia's minor NSR permitting program is triggered. Section 3.0 includes the necessary emissions calculations. Based on that analysis, the Project is subject to Virginia's minor NSR permitting program for all pollutants except lead. Section 5.0 presents the necessary state-level BACT analysis for these pollutants.

**9 VAC 5-80-1180, Standards and Conditions for Granting Permits**

This regulation outlines the standards required for facilities for which a permit is granted. The proposed facility will comply with all standards and conditions listed in the regulation.

**9 VAC 5-80-1210, Permit Invalidation, Suspension, Revocation, and Enforcement**

This regulation describes the conditions in which a permit may be invalidated, suspended, or revoked or an enforcement action may be brought upon the facility.

**9 VAC 5-80-1715, Source Impact Analysis**

The proposed facility must demonstrate the proposed equipment does not have emissions increases that would cause or contribute to air pollution in violation of AAQS or the maximum allowable increase over the baseline concentration in any area. The facility has conducted modeling to demonstrate compliance with this regulation. Sections 6.0 and 7.0 describe the modeling.

**9 VAC 5-80-1785, Source Obligation**

This regulation describes the information the proposed facility is required to maintain onsite prior to construction. The proposed facility will comply with this regulation.

Table 4-9. Virginia Minor NSR Thresholds

Pollutant	Minor Source Threshold (tpy)
CO	100
NO <sub>x</sub>	40
SO <sub>2</sub>	40
PM	25
PM <sub>10</sub>	15
PM <sub>2.5</sub>	10
VOC	25
Lead	0.6
H <sub>2</sub> SO <sub>4</sub>	6

Source: 9 VAC 5-80-1105.C.1.

## 5.0 Control Technology Review

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### 5.1 Applicable Air Pollution Control Requirements

The proposed Project is subject to review with respect to the following control technology requirements:

- BACT for those pollutants that exceed PSD SER thresholds specified in 40 CFR 52.21(b)(23) and 9 VAC 5-80-1615.C for which Charles City County is classified as attainment.
- BACT for GHG emissions if the total facility CO<sub>2</sub>e potential emissions exceed 75,000 tpy and the facility is subject to PSD review for a regulated non-GHG pollutant, or if the total facility CO<sub>2</sub>e potential emissions exceed 100,000 tpy.

BACT requirements apply to each air emissions source at the facility that emits that particular pollutant. These analyses are discussed in the following subsections.

### 5.2 Top-Down BACT Analysis

A BACT analysis is required for any pollutants subject to the PSD regulations. BACT is defined in the PSD regulations and is defined by VDEQ under 9 VAC 5-80-1615.C as “an emissions limitation (including a visible emissions standard) based on the maximum degree of reduction for each regulated NSR pollutant that would be emitted from any proposed major stationary source or major modification that the board, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant.”

Both EPA and VDEQ recommend a top-down approach to the BACT analysis. BACT analyses were performed in accordance with EPA’s top-down method. The first step in the top-down

BACT procedure is the identification of available control technologies. Alternatives considered included process designs and operating practices that reduce the formation of emissions, postprocess stack controls that reduce emissions after they are formed, and combinations of these two control categories. Sources of information used to identify control alternatives include:

- EPA's Reasonably Available Control Technology (RACT)/BACT/Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC) database.
- Vendor information.
- ECT's experience with similar projects.

Following the identification of available control technologies, the second step in the analysis is to determine which technologies may be technically infeasible. Technical feasibility was evaluated using the criteria contained in Chapter B of the draft EPA NSR Workshop Manual (EPA, 1990). The third step in the top-down BACT process is the ranking of the remaining technically feasible control technologies from high to low in order of control effectiveness.

An assessment of energy, environmental, and economic impacts is then performed as step four. The economic analysis procedures can be found in the Office of Air Quality Planning and Standards Control Cost Manual (EPA, 2002). The fifth and final step is the selection of a BACT emissions limitation or a design, equipment, work practice, operational standard, or combination thereof corresponding to the most stringent, technically feasible control technology that was not eliminated based on adverse energy, environmental, or economic grounds.

If the most stringent or top control technology is selected, an assessment of energy and economic impacts is not required. In this case, a review of collateral environmental impacts is conducted to determine if selection of a less stringent alternative control technology is warranted. If there are no issues regarding collateral environmental impacts, the top control technology is proposed as BACT, and the BACT analysis is concluded.

The following sections provide control technology analyses using the five-step top-down BACT method for NO<sub>x</sub>, CO, VOC, PM/PM<sub>10</sub>/PM<sub>2.5</sub>, H<sub>2</sub>SO<sub>4</sub>, and GHG emissions for all equipment emitting pollutants subject to this analysis.

## 5.3 CT/HRSG BACT Analysis

### 5.3.1 BACT for NO<sub>x</sub>

NO<sub>x</sub> emissions from combustion sources such as CT/HRSGs consist of two components: oxidation of combustion air atmospheric nitrogen (thermal NO<sub>x</sub> and prompt NO<sub>x</sub>) and conversion of chemically bound fuel nitrogen (FBN) (fuel NO<sub>x</sub>). Essentially all NO<sub>x</sub> emissions originate as nitric oxide (NO). NO generated by the CT combustion processes are subsequently further oxidized in the atmosphere to the more stable NO<sub>2</sub> molecule.

Thermal NO<sub>x</sub> results from the oxidation of atmospheric nitrogen under high temperature combustion conditions. The amount of thermal NO<sub>x</sub> formed is primarily a function of combustion temperature and residence time, air/fuel ratio, and, to a lesser extent, combustion pressure. Thermal NO<sub>x</sub> increases exponentially with increases in temperature and linearly with increases in residence time as described by the Zeldovich mechanism.

Prompt NO<sub>x</sub> is formed near the combustion flame front from the oxidation of intermediate combustion products. Prompt NO<sub>x</sub> comprises a small portion of total NO<sub>x</sub> in conventional near-stoichiometric combustors but increases under fuel-lean conditions. Prompt NO<sub>x</sub>, therefore, is an important consideration with respect to low-NO<sub>x</sub> combustors that use lean fuel mixtures. Prompt NO<sub>x</sub> levels may also become significant with ultra-low-NO<sub>x</sub> burners. Fuel NO<sub>x</sub> arises from the oxidation of nonelemental nitrogen contained in the fuel. The conversion of FBN to NO<sub>x</sub> depends on the bound nitrogen content of the fuel. In contrast to thermal NO<sub>x</sub>, fuel NO<sub>x</sub> formation does not vary appreciably with combustion variables such as temperature or residence time. Presently, there are no combustion processes or fuel treatment technologies available to control fuel NO<sub>x</sub> emissions. For this reason, the regulations typically contain an allowance for FBN directly or inherently (i.e., part of the emissions limit). NO<sub>x</sub> emissions from combustion sources fired with fuel oil are higher than those fired with natural gas due to higher combustion flame temperatures and FBN contents. Natural gas may contain molecular nitrogen (N<sub>2</sub>); however, the molecular nitrogen found in natural gas does not contribute significantly to fuel NO<sub>x</sub> formation. Typically, natural gas contains a negligible amount of FBN.

#### 5.3.1.1 Available NO<sub>x</sub> Control Technologies (Step 1)

Available technologies for controlling NO<sub>x</sub> emissions from CTs and HRSGs include combustion process modifications and postcombustion exhaust gas treatment systems. A listing of available technologies for each of these categories follows:

- Combustion process modifications:
  - Water or steam injection and standard combustor design (CTs).
  - Water or steam injection and advanced combustor design (CTs).
  - Dry low-NO<sub>x</sub> combustor design (CTs).
  - Catalytic combustion controls (CTs).
- Postcombustion exhaust gas treatment systems:
  - Selective noncatalytic reduction (SNCR).
  - Nonselective catalytic reduction (NSCR).
  - SCR.
  - SCONOX<sup>TM</sup>

A description of each of the listed control technologies is provided in the following subsections.

#### Water or Steam Injection and Standard Combustor Design

Injection of water or steam into the primary combustion zone of a CT reduces the formation of thermal NO<sub>x</sub> by decreasing the peak combustion temperature. Water injection decreases the peak flame temperature by diluting the combustion gas stream and acting as a heat sink by absorbing heat necessary to vaporize the water (latent heat of vaporization) and raise the vaporized water temperature to the combustion temperature. High purity water must be employed to prevent turbine corrosion and deposition of solids on the CT blades. Steam injection employs the same mechanisms to reduce peak flame temperature with the exclusion of heat absorbed due to vaporization, because the heat of vaporization has been added to the steam prior to injection. Accordingly, a greater amount of steam, on a mass basis, is required to achieve a specified level of NO<sub>x</sub> reduction in comparison to water injection. Typical injection rates range from 0.3 to 1.0 and 0.5 to 2.0 lb of water and steam, respectively, per pound of fuel. Water or steam injection will not reduce the formation of fuel NO<sub>x</sub>.



The maximum amount of steam or water that can be injected depends on the CT combustor design. Excessive rates of injection will cause flame instability, combustor dynamic pressure oscillations, thermal stress (cold-spots), and increased emissions of CO and VOCs due to combustion inefficiency. Accordingly, the efficiency of steam or water injection to reduce NO<sub>x</sub> emissions also depends on turbine combustor design. For a given CT design, the maximum water to fuel ratio (and maximum NO<sub>x</sub> reduction) will occur up to the point where cold-spots and flame instability adversely affect safe, efficient, and reliable operation of the turbine.

The use of water or steam injection and standard turbine combustor design can generally achieve NO<sub>x</sub> exhaust concentrations of 42 ppmvd for gas firing.

#### **Water or Steam Injection and Advanced Combustor Design**

Water or steam injection functions in the same manner for advanced combustor designs as described previously for standard combustors. Advanced combustors, however, have been designed to generate lower levels of NO<sub>x</sub> and tolerate greater amounts of water or steam injection. The use of water or steam injection and advanced turbine combustor design can typically achieve NO<sub>x</sub> exhaust concentrations of 25 ppmvd for gas firing.

#### **Dry Low-NO<sub>x</sub> Combustor Design**

Dry low-NO<sub>x</sub> combustors are designed to premix CT fuel and air prior to combustion in the primary zone. Use of a premix burner results in a homogeneous air/fuel mixture without an identifiable flame front. This allows a lower flame temperature in the combustion zone, causing a decrease in thermal NO<sub>x</sub> emissions.

Currently, premix burners are limited in application to natural gas and loads above approximately 35 to 50 percent of baseline due to flame stability considerations. During oil-firing, water injection is typically employed to control NO<sub>x</sub> emissions.

In addition to lean premixed combustion, dry low-NO<sub>x</sub> combustors typically incorporate lean combustion and reduced combustor residence time to reduce the rate of NO<sub>x</sub> formation. CTs cool the high-temperature CT combustor discharge gas stream with dilution air to lower the exhaust gas to an acceptable temperature prior to entering the turbine. By adding additional dilution air,

the hot CT combustor gases are rapidly cooled to temperatures below those needed for NO<sub>x</sub> formation. Reduced residence time combustors add the dilution air sooner than do standard combustors. The amount of thermal NO<sub>x</sub> is reduced, because the CT combustion gases are at a higher temperature for a shorter period of time.

Current dry low-NO<sub>x</sub> combustor technology can typically achieve NO<sub>x</sub> exhaust concentrations of approximately 9 ppmvd or less using natural gas fuel, depending on the CT vendor.

#### **Catalytic Combustion Controls (XONON™)**

Another technology that is potentially capable of reducing gas turbine NO<sub>x</sub> emissions to less than 3.5 ppmvd is catalytic combustion. Catalytica, Inc., was the first to commercially develop catalytic combustion controls for certain (mostly smaller) turbine engines and markets this system under the name XONON™. In October 2006, this technology was sold to Kawasaki Heavy Industries, Ltd. It is not commercially available for larger CTs. Therefore, catalytic combustion does not represent an available control option for the proposed CT.

#### **Selective Noncatalytic Reduction**

The SNCR process involves the gas phase reaction, in the absence of a catalyst, of NO<sub>x</sub> in the exhaust gas stream with injected ammonia or urea to yield nitrogen and water vapor. The two commercial applications of SNCR include the Electric Power Research Institute's NO<sub>x</sub>OUT™ and Exxon's Thermal DeNO<sub>x</sub>™ processes. The two processes are similar in that either ammonia (Thermal DeNO<sub>x</sub>™) or urea (NO<sub>x</sub>OUT™) is injected into a hot exhaust gas stream at a location specifically chosen to achieve the optimum reaction temperature and residence time. Simplified chemical reactions for the Thermal DeNO<sub>x</sub>™ process are as follows:



The NO<sub>x</sub>OUT™ process is similar with the exception that urea is used in place of ammonia. The critical design parameter for both SNCR processes is the reaction temperature. At temperatures below 1,600°F, rates for both reactions decrease allowing unreacted ammonia to exit with the exhaust stream. Temperatures between 1,600 and 2,000°F will favor reaction (1), resulting in a reduction in NO<sub>x</sub> emissions. Reaction (2) will dominate at temperatures above approximately

2,000°F, causing an increase in NO<sub>x</sub> emissions. Due to reaction temperature considerations, the SNCR injection system must be located at a point in the exhaust duct where temperatures are consistently between 1,600 and 2,000°F.

### **Nonselective Catalytic Reduction**

The NSCR process uses a platinum/rhodium catalyst to reduce NO<sub>x</sub> to nitrogen and water vapor under fuel-rich (less than 3 percent oxygen gas [O<sub>2</sub>]) conditions. NSCR technology has only been applied to automobiles and stationary reciprocating engines.

### **Selective Catalytic Reduction**

In contrast to SNCR, SCR reduces NO<sub>x</sub> emissions by reacting ammonia with exhaust gas NO<sub>x</sub> to yield nitrogen and water vapor in the presence of a catalyst. Ammonia is injected upstream of the catalyst bed where the following primary reactions take place:



The catalyst serves to lower the activation energy of these reactions, which allows NO<sub>x</sub> conversions to take place at a lower temperature than the exhaust gas. The optimum temperatures range from as low as 350°F to as high as 1,100°F (typically 600 to 750°F), depending on the catalyst. Typical SCR catalysts include metal oxides (titanium oxide and vanadium), noble metals (combinations of platinum and rhodium), zeolite (alumino-silicates), and ceramics.

Factors affecting SCR performance include space velocity (volume per hour of flue gas divided by the volume of the catalyst bed), ammonia/NO<sub>x</sub> molar ratio, and catalyst bed temperature. Space velocity is a function of catalyst bed depth. Decreasing the space velocity (increasing catalyst bed depth) will improve NO<sub>x</sub> removal efficiency by increasing residence time but will also cause an increase in catalyst bed pressure drop. The reaction of NO<sub>x</sub> with ammonia theoretically requires a 1:1 molar ratio. Ammonia/NO<sub>x</sub> molar ratios greater than 1:1 are necessary to achieve high NO<sub>x</sub> removal efficiencies due to imperfect mixing and other reaction limitations. However, ammonia/NO<sub>x</sub> molar ratios are typically maintained at 1:1 or lower to prevent excessive unreacted ammonia (ammonia slip) emissions. As was the case for SNCR, reaction temperature is critical for proper SCR operation. Below this critical temperature range,

reduction reactions (3) and (4) will not proceed. At temperatures exceeding the optimal range, oxidation of ammonia will take place resulting in an increase in NO<sub>x</sub> emissions. NO<sub>x</sub> removal efficiencies for SCR systems typically range from 80 to 90 percent.

### **EMx™ (SCONox™)**

EMx™ (formerly referred to as SCONox™) is a multipollutant reduction catalytic control system offered by EmeraChem. EMx™ is a complex technology that is designed to simultaneously reduce NO<sub>x</sub>, VOC, and CO through a series of oxidation/absorption catalytic reactions.

The EMx™ system employs a single catalyst to simultaneously oxidize CO to CO<sub>2</sub> and NO to NO<sub>2</sub>. NO<sub>2</sub> formed by the oxidation of NO is subsequently absorbed onto the catalyst surface through the use of a potassium carbonate absorber coating. The EMx™ oxidation/absorption cycle reactions are:



CO<sub>2</sub> produced by reactions (5) and (7) is released to the atmosphere as part of the CT/HRSG exhaust stream. Water vapor and elemental nitrogen are released to the atmosphere as part of the CT/HRSG exhaust stream. Following regeneration, the EMx™ catalyst has a fresh coating of potassium carbonate, allowing the oxidation/absorption cycle to begin again. Because the regeneration cycle must take place in an oxygen-free environment, the section of catalyst undergoing regeneration is isolated from the exhaust gas stream using a set of louvers.

The EMx™ operates at a temperature range of 300 to 700°F and, therefore, must be installed in the appropriate temperature section of a HRSG. For installations below 450°F, the EMx™ system uses an inert gas generator for the production of hydrogen and CO<sub>2</sub>. For installations above 450°F, the EMx™ catalyst is regenerated by introducing a small quantity of natural gas with a carrier gas, such as steam, over a steam reforming catalyst and then to the EMx™ catalyst. The reforming catalyst initiates the conversion of methane to hydrogen, and the conversion is completed over the EMx™ catalyst. Utility materials needed for the operation of the EMx™

control system include ambient air, natural gas, water, steam, and electricity. The primary utility material is natural gas used for regeneration gas production. Steam is used as the carrier/dilution gas for the regeneration gas. Electricity is required to operate the computer control system, control valves, and louver actuators.

Commercial experience to date with the EMx™ control system is limited to several small combined-cycle power plants located in California. Representative of these small power plants is a GE LM2500 turbine, owned by Sunlaw Energy Corporation, equipped with water injection to control NO<sub>x</sub> emissions to approximately 25 ppmvd. The low temperature SCONOx™ control system (i.e., located downstream of the HRSG at a temperature between 300 and 400°F) was retrofitted to the Sunlaw Energy facility in December 1996 and has achieved a NO<sub>x</sub> exhaust concentration of 3.5 parts per million by volume (ppmv) resulting in an approximate 85-percent NO<sub>x</sub> removal efficiency. This facility is no longer operating due to market factors. A high-temperature application of EMx™ (i.e., control system located within the HRSG at a temperature between 600 and 700°F) has been in service since June 1999 on a small, 5-MW solar CT located at the Genetics Institute in Massachusetts. Although considered commercially available for large natural gas-fired CTs, there are currently no combined-cycle units larger than 43 MW that have demonstrated successful application of the EMx™ control technology.

#### 5.3.1.2 NO<sub>x</sub> BACT Technical Feasibility (Steps 2 and 3)

Water/steam injection and standard combustor design, water/steam injection and advanced combustor, and dry low-NO<sub>x</sub> combustor design would be feasible combustion processes for the project CT.

The CT is equipped with dry low-NO<sub>x</sub> burner technology.

Of the postcombustion stack gas treatment technologies, SNCR is not feasible because the temperature required for this technology (between 1,600 and 2,000°F) exceeds that which will be found in the CT gas streams (less than 1,500°F). NSCR was also determined to be technically infeasible because the process must take place in a fuel-rich (less than 3 percent oxygen) environment. The oxygen content of the proposed CT exhaust gases is in excess of 12 percent.

EMx<sup>TM</sup> is desirable in that it, unlike SCR, does not require ammonia. However, as discussed previously, there are many complex technical issues associated with this technology. In addition, this technology has not been proven on the size and model of combined-cycle CT being proposed. Furthermore, the installation of EMx<sup>TM</sup> technology would also cause an increase in the back pressure amounting to twice that of the SCR system and consume additional water to provide steam for the regeneration process, adding to both capital and operating costs.

SCR catalyst can be subject to deactivation by a number of mechanisms. Loss of catalyst activity can occur from thermal degradation if the catalyst is exposed to excessive temperatures over a prolonged period of time. Catalyst deactivation can also occur due to chemical poisoning. Principal poisons include arsenic, sulfur, potassium, sodium, and calcium. Another consideration with the application of SCR technology is the possibility of fouling (i.e., formation of sticky ammonium sulfates and plugging the catalyst bed surfaces over time). This is caused by the use of high sulfur fuels and is especially problematic for combined-cycle operations using HRSGs. The proposed CT will combust pipeline-quality natural gas. Furthermore, ammonia slip will be limited to 5 ppmvd (three-hour average). Therefore, potential for poisoning or fouling the catalyst from the proposed CT operations is expected to be minimal. To ensure optimal performance of the catalyst, C4GT will monitor NO<sub>x</sub> emissions, perform periodic ammonia slip testing, closely monitor ammonia inventory and flow rate, and undertake periodic physical inspections of the catalyst bed (e.g., through the placement of coupons in the bed that will be monitored and analyzed on an as-needed basis to assess catalyst life).

#### 5.3.1.3 Proposed NO<sub>x</sub> BACT Emissions Limit (Steps 4 and 5)

To determine the most stringent NO<sub>x</sub> emissions limit for the CTs/HRSGs, EPA's RBLC database was queried for large CTs. BACT determinations were obtained when combusting pipeline-quality natural gas for the past ten years and are summarized in Appendix C, Table C-1. As shown, the lowest NO<sub>x</sub> emissions limit is 2 ppmvd (three-hour average) at 15-percent oxygen gas for natural gas-fired CTs. The typical control system used to achieve these emissions limits is dry low-NO<sub>x</sub> combustors and SCR for natural gas-firing.

The proposed NO<sub>x</sub> BACT emissions rate for each CT/HRSG when combusting natural gas is 2 ppmvd at 15-percent oxygen gas based on a three-hour average for base or peak load operating

cases with or without duct firing. This proposed NO<sub>x</sub> BACT emissions rate is consistent with previous and recent BACT determinations. Table 5-1 provides a summary of the proposed NO<sub>x</sub> BACT emissions limits for each CT/HRSG. The proposed control system to achieve these emissions limits is dry low-NO<sub>x</sub> combustors and SCR.

### **5.3.2 BACT for CO**

#### **5.3.2.1 Available CO Control Technologies (Step 1)**

The two technologies available for controlling CO include combustion process design and oxidation catalyst. With respect to oxidation catalyst control technology, lower temperatures (on the order of 500°F) are needed to oxidize CO.

#### **5.3.2.2 CO BACT Technical Feasibility (Steps 2 and 3)**

Both CT combustor/burner design and oxidation catalyst control systems are considered to be technically feasible for the proposed CT. There are no significant adverse energy or environmental impacts associated with the use of good combustor designs and operating practices to minimize CO emissions. However, the use of oxidation catalysts will, as previously noted, result in increased H<sub>2</sub>SO<sub>4</sub> mist and salt emissions if applied to combustion devices fired with fuels containing appreciable amounts of sulfur. Increased H<sub>2</sub>SO<sub>4</sub> mist emissions will occur, on a smaller scale, from the proposed CT. The oxidation catalyst does not remove CO but rather simply accelerates the natural atmospheric oxidation of CO to CO<sub>2</sub>. Because the use of oxidation catalyst represents top control technology, it is not necessary to conduct detailed energy and economic impact analyses.

#### **5.3.2.3 Proposed CO BACT Emissions Limit (Steps 4 and 5)**

To determine the most stringent CO emissions limit for the CTs/HRSGs, EPA's RBLC database was queried for large CTs firing natural gas. BACT and LAER determinations were obtained for the past ten years and are summarized in Appendix C, Table C-2.

There are several BACT determinations at levels below those being proposed by C4GT. A number of these are draft determinations; therefore, the facility has not been built, and the limits have not been demonstrated. The lowest determinations for natural gas firing without duct burner firing are 0.9 ppmvd at 15-percent oxygen gas at the CPV Towantic LLC facility in Connecticut

Table 5-1. Proposed NO<sub>x</sub> BACT Emissions Limits for CTs/HRSGs

Emissions Source	Proposed NO <sub>x</sub> BACT Emissions Limits, Three-Hour Average
Natural gas-firing – CT/HRSG (up to and including peak load operation with or without duct burner firing)	2 ppmvd*

\*Corrected to 15-percent oxygen gas.

Sources: GE, 2016.  
C4GT, 2016



and the West Deptford facility in New Jersey. The New Jersey facility has a BACT determination of 1.5 ppmvd at 15-percent oxygen gas with duct burner firing. Also, there are three determinations for natural gas firing with duct burner firing at 1.5 ppmvd at 15-percent oxygen gas and one at 1.8 ppmvd at 15-percent oxygen gas.

There are upwards of 50 RBLC determinations, both nondraft and draft, ranging from 2 to 15 ppmvd. This includes a recent final determination of 2 ppmvd at the fossil LLC Sewaren Generating Station in New Jersey. Of these determinations, over half are greater than 2 ppmvd.

The proposed CO BACT emissions limit for the CTs/HRSGs is 2 ppmvd at 15-percent oxygen gas (three-hour average) for all natural gas operating cases. Table 5-2 provides proposed CO BACT emissions limits. These proposed CO BACT emissions limits are consistent with typical emissions limits. Compliance will be achieved through good combustion practices (GCP) and oxidation catalyst. C4GT plans to inspect the catalyst on an as-needed basis and will place coupons in the catalyst bed to analyze as needed the functionality and ensure the performance of the catalyst.

### 5.3.3 BACT for VOCs

VOC emissions result from the incomplete combustion of carbon and organic compounds. Factors affecting VOC emissions include firing temperatures, residence time in the combustion zone, and combustion chamber mixing characteristics. Because higher combustion temperatures will increase oxidation rates, emissions of VOC will generally increase during turbine partial load conditions when combustion temperatures are lower. Generally, decreased combustion zone temperature due to the injection of water or steam for NO<sub>x</sub> control will also result in an increase in VOC emissions. An increase in combustion zone residence time and improved mixing of fuel and combustion air will increase oxidation rates and cause a decrease in VOC emissions rates. Emissions of NO<sub>x</sub> and VOC are inversely related (i.e., decreasing NO<sub>x</sub> emissions will result in an increase in VOC emissions). Accordingly, CT vendors have had to consider the competing factors involved in NO<sub>x</sub> and VOC formation to develop units that achieve acceptable emissions levels for both pollutants.

Table 5-2. Proposed CO BACT Emissions Limit for CTs/HRSGs

Emissions Source	Proposed CO BACT Emissions Limits, Three-Hour Average
Natural gas-firing – CT/HRSG (up to and including peak load operation with or without duct burner firing)	2 ppmvd*

\*Corrected to 15-percent oxygen gas.

Sources: GE, 2016.  
C4GT, 2016

#### 5.3.3.1 Available VOC Control Technologies (Step 1)

There are two available technologies for controlling VOC from gas turbines: combustion process design and oxidation catalyst.

##### Combustion Process Design

Combustion process controls involve combustion chamber designs and operation practices that improve the oxidation process and minimize incomplete combustion. Because of the high combustion efficiency of CTs (approximately 99 percent), VOC emissions are inherently low.

##### Oxidation Catalyst

Noble metal (commonly platinum or palladium) oxidation catalysts are used to promote oxidation of VOC to CO<sub>2</sub> and water at temperatures lower than would be necessary for oxidation without a catalyst. The design operating temperature range for oxidation catalysts is between 650 and 1,150°F.

Efficiency of VOC oxidation varies with inlet temperature. Control efficiency will increase with increasing temperature up to a temperature of approximately 1,100°F; further temperature increases will have little effect on control efficiency. Significant VOC oxidation will occur at any temperature above roughly 900°F. Inlet temperature must also be maintained below 1,350 to 1,400°F to prevent thermal aging of the catalyst, which will reduce catalyst activity and pollutant removal efficiencies. Removal efficiency will also vary with gas residence time, which is a function of catalyst bed depth. Increasing bed depth will increase removal efficiencies but will also cause an increase in pressure drop across the catalyst bed.

VOC removal efficiency will vary with the species of hydrocarbon. In general, unsaturated hydrocarbons such as ethylene are more reactive with oxidation catalysts than saturated species such as ethane. A typical VOC control efficiency using oxidation catalyst is in the range of 30 to 50 percent.

Oxidation catalysts are susceptible to deactivation due to impurities present in the exhaust gas stream. Arsenic, iron, sodium, phosphorous, and silica (typically present in fuel oil) will all act as catalyst poisons causing a reduction in catalyst activity and pollutant removal efficiencies.

Oxidation catalysts are also nonselective and will oxidize other compounds in addition to VOC. The nonselectivity of oxidation catalysts is important in assessing applicability to exhaust streams containing sulfur compounds. Sulfur compounds that have been oxidized to SO<sub>2</sub> in the combustion process will be further oxidized by the catalyst to sulfur trioxide (SO<sub>3</sub>). Higher SO<sub>3</sub> concentrations increase the potential for formation of ammonia salt particles and H<sub>2</sub>SO<sub>4</sub> mist. These substances may condense and stick to the ductwork and stack, resulting in corrosion and increased maintenance. Because of the oxidation of sulfur compounds and excessive formation of H<sub>2</sub>SO<sub>4</sub> mist emissions, oxidation catalysts are not considered appropriate for combustion devices fired with fuels containing appreciable amounts of sulfur. The exclusive use of low-sulfur natural gas is proposed for the project.

#### **5.3.3.2 VOC BACT Technical Feasibility (Steps 2 and 3)**

Both combustion process design and oxidation catalysts are considered technically feasible for the facility's CTs/HRSGs, despite the potential drawbacks cited. However, the application of oxidation catalyst represents the top level of control and, therefore, BACT for the CTs/HRSGs.

#### **5.3.3.3 Proposed VOC BACT Emissions Limit (Steps 4 and 5)**

To determine the BACT VOC emissions limit for the CTs/HRSGs, EPA's RBLC database was queried for large CTs firing natural gas. BACT determinations were obtained for the past ten years and are summarized in Appendix C, Table C-3.

The lowest VOC concentration for a natural gas-fired CT without duct firing listed in the RBLC database is 0.3 ppmvd at 15-percent oxygen gas for the Chouteau Power Plant in Mayes County, Oklahoma. There are numerous records of VOC emissions rates ranging from 0.7 to 1.9 ppmvd at 15-percent oxygen gas. However, the majority are either draft determinations of which achievable emissions have not yet been demonstrated, or which represent LAER determinations. Of other nondraft, BACT determinations for natural gas-fired CTs without duct firing listed in the RBLC database, no determination is less than 1 ppmvd at 15-percent oxygen gas.

There are also numerous BACT determinations that range between 2 and 5 ppmvd at 15-percent oxygen gas within the RBLC database. Recent draft and nondraft determinations within this range include facilities located in California, Colorado, Georgia, Idaho, Illinois, Maryland,

Michigan, Minnesota, New Jersey, Oklahoma, Oregon, Pennsylvania, Texas, and Wyoming. The proposed VOC BACT emissions limit for the CTs/HRSGs is 1.0 ppmvd without duct burner and 3.6 ppmvd with duct burner (both three-hour average), as summarized in Table 5-3. This proposed VOC emissions limit is consistent with typical BACT emissions limits for VOC. Compliance will be achieved through GCP and oxidation catalyst. C4GT plans to inspect the catalyst on a periodic basis and to place coupons in the catalyst bed to assess and ensure its functionality and performance.

### 5.3.4 BACT for PM, PM<sub>10</sub>, and PM<sub>2.5</sub>

#### 5.3.4.1 Available PM/PM<sub>10</sub>/PM<sub>2.5</sub> Control Technologies (Step 1)

EPA's RBLC database was queried for large CTs firing natural gas. BACT determinations were obtained for the past ten years and are summarized in Appendix C, Table C-4.

Available postcontrol technologies used for controlling PM emissions include the following:

- Centrifugal (cyclone) collectors.
- Electrostatic precipitators.
- Fabric filters or baghouses.
- Wet scrubbers.

There are no postcombustion control systems for PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions that have been applied to CTs, since exhaust gas PM concentrations are inherently low.

#### 5.3.4.2 PM/PM<sub>10</sub>/PM<sub>2.5</sub> BACT Technical Feasibility (Steps 2 and 3)

There are no technically feasible postcombustion control systems that control PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions from CTs. Therefore, it is difficult to make comparisons of numerical BACT emissions limits with respect to PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions for a couple reasons. First, some of the queried results represent emissions limits based on only the filterable portion of total PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions. If the condensable portion, including sulfates generated during the combustion process, is not included, a lower lb/MMBtu emissions limit will result. Second, the emissions limits that do contain both the filterable and condensable portion are based on widely varying natural gas sulfur contents. Sulfur in the fuel is converted to sulfates during the combustion process, and these sulfates add to the condensable portion of the total PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions. Facilities that have a higher short-term natural gas sulfur content have higher PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions based solely on the condensable portion.

Table 5-3. Proposed VOC BACT Emissions Limit for CTs/HRSGs

Emissions Source	Proposed VOC BACT Emissions Limits, Three-Hour Average
Natural gas firing – CT/HRSG (up to and including peak load operation with or without duct burner firing)	2 ppmvd*

\*Corrected to 15-percent oxygen gas.

Sources: GE, 2016.  
C4GT, 2016

**5.3.4.3 Proposed PM/PM<sub>10</sub>/PM<sub>2.5</sub> BACT Emissions Limit (Steps 4 and 5)**

PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions from CTs are dependent on several factors: one, the manufacturer and model of the CT; two, the sulfur content of the fuel; and three, the use of a postcombustion SCR and/or oxidation catalyst control system. While an SCR and oxidation catalyst controls other pollutants, their use and the introduction of ammonia can increase PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions. In addition, some PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions rates are expressed in terms of filterable particulates only, and some are expressed in terms of filterable and condensable particulates. Therefore, it is difficult to compare PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions rates between facilities as different CT manufacturers, different natural gas sulfur content, and different assumptions used in calculating the conversion of ammonia to ammonium sulfates affects the PM/PM<sub>10</sub>/PM<sub>2.5</sub> emissions rate.

The proposed PM/PM<sub>10</sub>/PM<sub>2.5</sub> BACT for the two CTs/HRSGs is the exclusive use of pipeline-quality natural gas as the primary fuel.

**5.3.5 BACT for H<sub>2</sub>SO<sub>4</sub>****5.3.5.1 Available H<sub>2</sub>SO<sub>4</sub> Control Technologies (Step 1)**

There are no postcombustion control systems, such as scrubbers or duct sorbent injection, for H<sub>2</sub>SO<sub>4</sub> emissions that have been applied to CTs.

**5.3.5.2 H<sub>2</sub>SO<sub>4</sub> BACT Technical Feasibility (Steps 2 and 3)**

There are no postcombustion control systems that are technically feasible to control H<sub>2</sub>SO<sub>4</sub> emissions from CTs.

**5.3.5.3 Proposed H<sub>2</sub>SO<sub>4</sub> BACT Emissions Limit (Steps 4 and 5)**

Only two nondraft BACT determinations for H<sub>2</sub>SO<sub>4</sub> expressed as mass per heat input were identified in the RBLC database (see Appendix C, Table C-5). These were 0.0001 lb/MMBtu for the Warren County Power Plant in Virginia and 0.0004 lb/MMBtu for the Caithnes Bellport Energy Center in New York. The majority of the BACT determinations list use of low-sulfur natural gas as the control method.

C4GT proposes the exclusive use of pipeline-quality natural gas in the CTs/HRSGs as BACT for H<sub>2</sub>SO<sub>4</sub>.

### 5.3.6 BACT for GHG Emissions

On June 3, 2010, EPA published a final rule (effective August 2, 2010) in the Federal Register (75 FR 106) entitled PSD and Title V GHG Tailoring Rule, commonly referred to as the Tailoring Rule. For PSD/Title V purposes, GHGs are a single air pollutant defined as the aggregate group of CO<sub>2</sub>, nitrous oxide, methane, hydrofluorocarbons, perfluorocarbons, and SF<sub>6</sub>. This final rule established specific applicability thresholds for GHG emissions for new major sources and modifications to existing major sources under the PSD and Title V programs. This was necessary, because applying the previous PSD and Title V applicability thresholds of 100 and 250 tpy to GHG emissions would have resulted in a large number of relatively small sources becoming subject to these regulatory programs.

Effective January 2, 2011, a new source or modification, that is a new major stationary source for an NSR pollutant other than GHG, whose GHG emissions exceed 75,000 tpy CO<sub>2e</sub> will be subject to PSD review, including a BACT analysis for GHG emissions. CO<sub>2e</sub> emissions are defined as the sum of the mass emissions of each individual GHG adjusted for its respective global warming potential using Table A-1 of the GHG Reporting Program (40 CFR 98, Subpart A). Effective July 1, 2011, in addition to this major stationary source applicability criterion, a new stationary source that emits more than 100,000 tpy of CO<sub>2e</sub> or an existing source that has the potential to emit 100,000 tpy of CO<sub>2e</sub> or greater and commences a modification that results in an emissions increase of 75,000 tpy of CO<sub>2e</sub> or greater will be subject to PSD and Title V programs.

The Project will be a new major stationary source for an NSR pollutant other than GHG and will have CO<sub>2e</sub> emissions greater than 75,000 tpy. Therefore, the Project will be subject to PSD review for GHG, including a BACT analysis effective January 2, 2011.

In March 2011, EPA published an updated version of the guidance document entitled PSD and Title V Permitting Guidance for Greenhouse Gases (EPA, 2011a). This guidance document, which was originally published in November 2010, provides, among other issues, guidance on



performing BACT analyses for GHG emissions. EPA's guidance reaffirms that a BACT analysis for GHG emissions must be conducted using the same five-step, top-down approach used for other NSR pollutants.

The following subsections provide the BACT analysis for GHG emissions required for the project.

The CT/HRSG will be the predominate source of GHGs emitted by the proposed project. The following describes the five-step BACT analysis performed for the CTs/HRSGs.

Step 1 of the top-down BACT analysis is the identification of available control technologies or techniques, including inherently lower-emitting processes/practices/designs, add-on controls, and a combination of inherently lower-emitting processes/practices and add-on controls, that have a practical application to the control of GHG emissions. These control technologies must include control technologies for the pollutant under evaluation, GHG, regardless of the source category type. For example, control technologies must be identified not only for those demonstrated on other combined-cycle CT facilities but also for control technologies determined through technology transfer that are applied to source categories with similar exhaust stream characteristics.

Technologies that formed the basis of an applicable NSPS should also be considered in the BACT analysis, since a BACT emissions limit cannot be less stringent than an applicable NSPS emissions limit.

On August 3, 2015, EPA proposed a federal plan to implement emissions guidelines for power plants under Section 111(d) of the CAA, known as the Clean Power Plan. On that date, EPA also finalized GHG NSPS, which are codified in 40 CFR 60, Subpart TTTT, for newly constructed, modified, and reconstructed utility steam electric generating units. The final NSPS apply to new electric generating units constructed after the date of publication of the proposed standards, June 18, 2014. NSPS define the best system of emissions reduction and standards of performance for newly constructed base load natural gas-fired, combined-cycle CTs as follows:

- Best system of emissions reduction equal to efficient natural gas-fired, combined-cycle technology for base load natural gas fired units.
- CO<sub>2</sub> emissions rate standards of 1,000 lb/MWh gross or 1,030 lb/MWh net.

It is important to note and must be emphasized that available control technologies should not include inherently lower-emitting processes, practices, or designs that would fundamentally redefine the nature of the proposed project or source. A BACT analysis should not consider those control technologies that would change or redefine that applicant's goal, objectives, purpose, or basic design. A BACT analysis may consider control technologies that change *aspects* of the proposed facility but do not redefine the *nature* of the proposed facility.

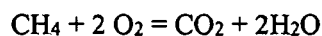
The plant configuration consists of two CTs/HRSGs in a 2×1, combined-cycle configuration. The analysis has determined that BACT for GHG emissions consists of maintaining a high-efficiency plant design inherent to this type of gas-fired power plant. A GHG BACT permit condition will be proposed that sets a net heat rate limit (equivalent to an efficiency limit) of British thermal units per kilowatt-hour (Btu/kWh), a heat rate appropriate to the proposed combination of gas turbine, HRSG, and steam turbine models. The Btu/kWh net heat rate will be based on the average of the heat rates associated with the primary plant operating mode, i.e., base load operation combusting natural gas with supplemental duct firing. This primary plant operating mode accounts for the majority of the total operating hours of the facility. Small degradation factors will also be applied to account for a design margin, performance degradation of the CT, and degradation of auxiliary equipment between major equipment overhauls. An emissions rate based on electrical output (i.e., lb/MWh CO<sub>2</sub>) will also be proposed.

#### 5.3.6.1 Available GHG Control Technologies (Step 1)

##### CT Energy Efficiency Designs, Practices, and Procedures

###### CT Design

CO<sub>2</sub> is a product of combustion of fuel containing carbon, which is inherent in any power generation technology using fossil fuel. The basic theoretical combustion equation for methane (CH<sub>4</sub>) is:



CO<sub>2</sub> emissions are the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. Therefore, CO<sub>2</sub> emissions cannot be reduced by improving the combustion efficiency, and there is no technology available that can reduce CO<sub>2</sub> generation from the combustion of carbon-based fuels. The only effective means to minimize the amount of CO<sub>2</sub> generated by a fuel-burning power plant is through high-efficiency combustion and plant design resulting in the lowest heat rate in units of Btu/kWh. Minimizing the amount of fuel required (in units of million British thermal units) to produce a given amount of electrical power output (in units of kilowatt-hours) results in the lowest amount of CO<sub>2</sub> generated during the combustion process.

The most efficient way to generate electricity from a natural gas CT plant is the use of a combined-cycle design. For fossil fuel technologies, efficiencies typically range between approximately 30 and 50 percent. A typical coal-fired Rankine cycle power plant has a typical base load efficiency of approximately 30 percent, while a natural gas-fired combined-cycle unit operating under optimal conditions has a base load efficiency of approximately 50 percent or greater.

Combined-cycle units operate based on a combination of two thermodynamic cycles: the Brayton and the Rankine cycles. A CT operates on the Brayton cycle, and the HRSG and steam turbine operate on the Rankine cycle. The combination of the two thermodynamic cycles allows for the high efficiency associated with combined-cycle plants.

The combined-cycle natural gas turbine technology proposed for the Project is the high efficiency GE 7HA CT. In addition to the high-efficiency primary components of the turbine, there are a number of other design features employed within the CT that can improve overall efficiency of the machine, including those summarized in the following paragraphs.

#### **Evaporative Inlet Air Cooling or Inlet Fogging**

Evaporative inlet air cooling or inlet fogging is used during middle and high ambient air temperature operating cases to lower the temperature of the inlet combustion air and thus increase the density of the combustion air. Increasing the density increases the mass flow rate of the inlet combustion air, which allows more fuel to be combusted in the CT process. This

provides greater electrical power output from the CT during certain operating cases and in cases of high electrical power demand. Increasing the electrical power output provides increased overall energy efficiency of the CT.

### **Periodic Burner Tuning**

CTs have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the CT is operated, the unit experiences degradation and loss in performance. The CT maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation and/or turbine starts. There are three basic maintenance levels: combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emissions operation.

### **Reduction in Heat Loss**

CTs have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the CT and protect personnel and equipment around the machine, insulation blankets are applied to the CT casing. These blankets minimize heat loss through the CT shell and help improve overall efficiency of the machine.

### **Instrumentation and Controls**

CTs have sophisticated instrumentation and controls to automatically control operation of the CT. The control system is a digital-type and is supplied with the CT. The distributed control system controls all aspects of the turbine's operation, including the fuel flow rate and burner operations to achieve high efficiency and low-NO<sub>x</sub> combustion. The control system monitors operation of the unit and modulates fuel flow and turbine operation to achieve optimal high-efficiency, low-emissions performance under all operating cases.